185 FERC ¶ 61,200
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Willie L. Phillips, Acting Chairman;
Allison Clements and Mark C. Christie.

PJM Interconnection, L.L.C. Docket No. ER24-163-000

ORDER ON ABANDONED PLANT INCENTIVE

(Issued December 19, 2023)

1. On October 20, 2023, Exelon Corporation (Exelon), on behalf of three of its affiliates, Baltimore Gas and Electric Company (BGE), PECO Energy Company (PECO), and Potomac Electric Power Company (Pepco), pursuant to sections 205 and 219 of the Federal Power Act (FPA),[1] Part 35 of the Commission's regulations,[2] and Order No. 679,[3] filed a request for authorization to recover 100% of prudently incurred costs associated with investment in certain transmission projects referred to as the Brandon Shores Project (the Project) in the event the Project is cancelled or abandoned for reasons beyond Exelon's control (Abandoned Plant Incentive).[4] As discussed below, we grant Exelon's request, effective December 20, 2023, as requested.

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[1] 16 U.S.C. §§ 824d, 824s.

[2] 18 C.F.R. pt. 35 (2022).

[3] *Promoting Transmission Inv. through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057, *order on reh'g*, Order No. 679-A, 117 FERC ¶ 61,345 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

[4] PJM Interconnection, L.L.C. (PJM) filed the proposed tariff revisions pursuant to Order No. 714, on behalf of Exelon. *See Elec. Tariff Filings*, Order No. 714, 124 FERC ¶ 61,270 (2008). Exelon states that PJM has agreed to make all filings on behalf of the PJM Transmission Owners in order to retain administrative control over the PJM Open Access Transmission Tariff (OATT). Transmittal at 1 n. 4. Under Order No. 714, a utility is required to include a tariff record to make a section 205 filing; to satisfy this requirement in cases where, as here, the tariff already contains a placeholder for recovery of these costs, one procedure that a utility may use is to include a non-substantive tariff record. *See Electronic Tariff Filings*, Docket No. RM01-5-000, Notice of Procedures for Making Statutory Filings when Authorization for New or Revised Tariff Provisions is not

I. Background and Filing

A. The Applicants

2. Exelon states that it is a publicly held corporation with operations and business activities in five states and the District of Columbia. Exelon states that BGE is an energy delivery company that operates in the state of Maryland. Exelon states that PECO is an energy delivery company in Pennsylvania. Exelon states that Pepco is an energy delivery company that serves the District of Columbia and surrounding Maryland suburbs and is a wholly owned subsidiary of Pepco Holdings, LLC, which is itself a wholly owned subsidiary of Exelon. Exelon states that BGE, PECO, and Pepco are members of PJM.[5]

B. The Project

3. Exelon states that the approximately $785 million Project is needed for reliability because of the announced retirement of Talen Energy's Unit 1 and Unit 2 at the 1,240 MW coal-fired Brandon Shores Generating Station, which is expected to occur on June 1, 2025.[6] Exelon states that PJM identified significant widespread voltage deviation violations due to the deactivation of Brandon Shores in multiple PJM service territories, including those of BGE, Pepco, and PECO. Additionally, PJM identified thermal violations on 115kV, 138kV, and 230kV lines in multiple PJM service territories, including BGE's and Pepco's, among other violations. Exelon states that these voltage and thermal violations must be mitigated so that grid reliability is maintained following the Brandon Shores Generating Station's retirement.[7] Exelon states that the Project involves several transmission projects in the service territories of BGE, PECO, and Pepco that would resolve these reliability criteria violations.

4. Exelon states that pursuant to its Regional Transmission Expansion Plan (RTEP) standards, PJM determined that BGE must construct eight components of the Project:

Required (June 3, 2020); *Pioneer Transmission, LLC*, 169 FERC ¶ 61,265 (2019) (Procedural Notice). PJM Interconnection, L.L.C., Intra-PJM Tariffs, OATT, attach. H-2 (Baltimore Gas & Electric) (3.0.0); *id*., OATT ATT H-7, OATT, attach. H-7 (PECO) (5.0.0); *id*., OATT, attach. H-9 (Potomac Electric) (3.0.0).

[5] Transmittal at 2-3.

[6] *Id.* at 3.

[7] *Id.* at 3-4.

(1) install new capacitor at Conastone substation at an estimated cost of $15 million; (2) reconductor the Batavia Road – Riverside 230 kV double circuit lines at an estimated cost of $21 million; (3) build the BGE portion of the new Peach Bottom – Graceton 500kV line at an estimated cost of $17 million; (4) build the new Solley Road substation by installing four additional 230 kV breaker bays in a breaker and half (BAAH) configuration at an estimated cost of $109 million; (5) expand Granite substation by building four additional 230 kV breaker bays into a BAAH configuration and install a new static synchronous compensator (STATCOM) at an estimated cost of $91 million; (6) build the new Batavia Road substation with four 230 kV breaker bays into a BAAH configuration at an estimated cost of $36 million; (7) expand Graceton substation by building three 500 kV breaker bays into a BAAH configuration and installing two banks of 500/230 kV transformers at an estimated cost of $82 million; and (8) build new Graceton – Batavia Road 230 kV double circuit lines at an estimated cost of $195 million.[8]

5. Exelon states that PJM determined that PECO must construct three components of the Project: (1) expand Peach Bottom North substation, by installing three 500 kV breakers to form a BAAH bay at an estimated cost of $33 million; (2) build the PECO portion of the new Peach Bottom-Graceton 500 kV line at an estimated cost of $48 million; and (3) build the new West Cooper substation by cutting into the existing Peach Bottom – Conastone 500 kV line, installing a three-breaker ring, 500/230 kV transformer, and control house, and resupplying the existing Cooper substation at an estimated cost of $60 million.[9]

6. Exelon states that PJM determined that Pepco must construct two components of the Brandon Shores Project: (1) install a new STATCOM and capacitor at Brighton substation at an estimated cost of $63 million; and (2) install a new capacitor at Burches Hill substation at an estimated cost of $15 million.[10]

C. <u>Exelon's Request</u>

7. Exelon requests recovery of 100 percent of abandonment costs incurred on and after the date of issuance of a Commission order granting this application.[11] Exelon requests that the Commission issue an order that authorizes the Abandoned Plant

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[8] *Id.*

[9] *Id.*

[10] *Id.* at 4-5.

[11] *Id.* at 6.

Incentive for the Project effective December 20, 2023.[12] Exelon states that it is already expending costs on these projects in an effort to meet in-service date targets to mitigate reliability risks and minimize potential customer out-of-market payments to the generator owner. Exelon states that the Abandoned Plant Incentive would be applied to project costs if the Project is abandoned, either in full or in part, for reasons outside the control of BGE, PECO, or Pepco.[13]

8. Exelon states that pursuant to the Procedural Notice, it is submitting the existing tariff records for Attachments H-2, H-7, and H-9 to the PJM OATT with an updated effective date of December 20, 2023, and is submitting this filing through eTariff.[14]

II. Notice of Filing and Response Pleadings

9. Notice of Exelon's filing was published in the *Federal Register*, 88 Fed. Reg. 74,172 (Oct. 30, 2023), with interventions and comments due on or before November 13, 2023. The Delaware Division of the Public Advocate, Maryland Office of People's Counsel, Old Dominion Electric Cooperative, Pennsylvania Office of Consumer Advocate, and Southern Maryland Electric Cooperative, Inc. each filed timely motions to intervene.

III. Discussion

A. Procedural Matters

10. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2022), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

B. Substantive Matters

1. Section 219 Requirement

11. In the Energy Policy Act of 2005, Congress added section 219 to the FPA, directing the Commission to establish, by rule, incentive-based rate treatments to promote capital investment in certain transmission infrastructure.[15] The Commission subsequently issued Order No. 679, establishing the processes by which a public utility may seek transmission rate incentives pursuant to section 219. Additionally, in November 2012, the Commission

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[12] *Id.* at 2, 5.

[13] *Id.* at 6.

[14] *Id.* at 13.

[15] Energy Policy Act of 2005, Pub. L. No. 109-58, § 1241, 119 Stat. 594 (2005).

issued a Policy Statement providing guidance regarding its evaluation of applications for transmission rate incentives under section 219 and Order No. 679.[16]

12. Pursuant to Order No. 679, an applicant may seek to obtain incentive rate treatment for a transmission infrastructure investment that satisfies the requirements of section 219; i.e., the applicant must show that "the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion."[17] Order No. 679 established a process for an applicant to demonstrate that it meets this standard, including a rebuttable presumption that the standard is met if: (1) "the transmission project results from a fair and open regional planning process that considers and evaluates the project for reliability and/or congestion and is found to be acceptable to the Commission;" or (2) "a project has received construction approval from an appropriate state commission or state siting authority."[18] The Commission also stated that "other applicants not meeting these criteria may nonetheless demonstrate that their project is needed to maintain reliability or reduce congestion by presenting [to the Commission] a factual record that would support such a finding."[19]

13. In addition to satisfying the section 219 requirement, Order No. 679 requires an applicant to demonstrate that there is a nexus between the incentive sought and the investment being made. In Order No. 679-A, the Commission clarified that the nexus test is met when an applicant demonstrates that the total package of incentives requested is "tailored to address the demonstrable risks or challenges faced by the applicant."[20] Applicants must provide sufficient support to allow the Commission to evaluate each

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[16] *Promoting Transmission Investment through Pricing Reform*, 141 FERC ¶ 61,129 (2012) (2012 Incentives Policy Statement).

[17] Order No. 679, 116 FERC ¶ 61,057 at P 76.

[18] *Id.* P 58.

[19] *Id.* P 57; *see also* Order No. 679-A, 117 FERC ¶ 61,345 at P 41.

[20] Order No. 679-A, 117 FERC ¶ 61,345 at P 27.

element of the package and the interrelationship of all elements of the package.[21] The Commission noted that this nexus test is fact-specific and requires the Commission to review each application on a case-by-case basis.[22]

2. Rebuttable Presumption

a. Exelon's Request

14. Exelon argues that the Project qualifies for the rebuttable presumption because it was approved in a regional transmission planning process, the PJM RTEP, and it will improve reliability.[23] Exelon argues that the PJM RTEP is a Commission-approved "fair and open regional planning process" that PJM uses to determine whether a project ensures reliability and reduces congestion.[24] Exelon concludes that the Project has been approved by the PJM Board for inclusion in the PJM RTEP as a baseline project and is thus entitled to the rebuttable presumption.

b. Commission Determination

15. The Commission has previously found that projects approved through a transmission planning process that evaluated whether the identified transmission projects will enhance reliability and/or reduce congestion are entitled to the rebuttable presumption established under Order No. 679.[25] In this case, PJM's RTEP, through which the Project was approved, evaluated whether the identified project would enhance reliability and/or reduce congestion.[26] Accordingly, we find that the Project is entitled to the rebuttable presumption and meets the requirements of FPA section 219.

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[21] 2012 Incentives Policy Statement, 141 FERC ¶ 61,129 at P 10 (quoting Order No. 679-A, 117 FERC ¶ 61,345 at P 27).

[22] Order No. 679, 116 FERC ¶ 61,057 at P 43.

[23] Transmittal at 7-8 (citing *PJM Interconnection, L.L.C.*, 158 FERC ¶ 61,089, at P 19 (2017).

[24] *Id.* at 8 (citing *PJM Interconnection, L.L.C.*, 133 FERC ¶ 61,273, at P 41 (2010); *Pub. Serv. Elec. & Gas Co.*, 129 FERC ¶ 61,300, at P 22 (2009); *Baltimore Gas & Elec. Co.*, 120 FERC ¶ 61,084, at P 41 (2007)).

[25] *See, e.g.*, *Duquesne Light Co.*, 179 FERC ¶ 61,218, at P 15 (2022).

[26] *Id.*; *see also Pub. Serv. Elec. & Gas Co.*, 129 FERC ¶ 61,300, at P 22 (2009) (finding that a baseline upgrade included in the PJM RTEP satisfies the rebuttable

3. Abandoned Plant Incentive

a. Exelon's Request

16. Exelon requests recovery of 100% of prudently incurred costs of the Project if it is abandoned for reasons beyond Exelon's control, i.e., the Abandoned Plant Incentive. Exelon requests that the Commission approve the recovery of all prudent expenditures incurred by BGE, PECO, and Pepco in connection with the Project, if it is subsequently abandoned, in whole or in part, for reasons beyond the control of BGE, PECO, or Pepco.[27] Exelon argues the Project satisfies the Commission's nexus test because the need for the Project has already been determined by PJM under its RTEP protocols, BGE, PECO, and Pepco have commenced all necessary action to obtain approval for, and undertake construction and operation of, their assigned portions of the Project, and they face numerous risks and challenges previously recognized as deserving of the requested incentive in similar situations.[28]

17. Exelon argues that the Project faces various risks and challenges beyond its control that could lead to delays of the Project or the Project potentially being abandoned. Exelon argues that the Abandoned Plant Incentive will help mitigate these risks. For example, Exelon argues that PJM's construction responsibility obligations imposed on BGE, PECO, and Pepco were driven by Talen Energy announcing its intent to retire Unit 1 and Unit 2 at Brandon Shores Generating Station.[29] Exelon argues that for any number of reasons, Talen Energy (or a successor owner) could make the business decision to withdraw its deactivation notice and instead either continue to own and operate its Brandon Shores Generating Station or sell its injection rights to another developer at that location. Given this uncertainty, Exelon argues that BGE, PECO, and Pepco are at the mercy of forces and decisions not of their own making as to whether PJM determines that the need for the Brandon Shores Project has evanesced PJM's in-service date directives.

18. Exelon also states that the Project could be affected by the New Jersey Offshore Wind State Agreement Approach-approved North Delta Project, which has redundancies with the Project that PJM has not yet resolved.[30] Exelon argues that both Maryland and New Jersey are in the process of conducting solicitations to procure offshore wind energy,

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presumption).

[27] Transmittal at 6.

[28] *Id.* at 9.

[29] *Id.*

[30] *Id.* at 9-10.

which will ultimately lead to the need to accommodate injections of power from offshore wind generators.[31] Exelon argues that the associated transmission needs are in the same general area of the grid and may further interact with, and require modification of, the Project. Further, Exelon argues that while the Project clearly addresses an independent and urgent reliability need due to the deactivations of Unit 1 and Unit 2 at Brandon Shores Generating Station, all of the other transmission planning activities in and around the same part of the PJM transmission system as the Project create the possibility that PJM will direct modification of the Project, in whole or in part, which creates risks and challenges that merit granting the Abandoned Plant Incentive.

19. Additionally, Exelon argues that there is a risk of local opposition from stakeholders, particularly landowners, because the Project will require a substantial number of miles of new facilities in existing rights-of-way, each of which will require certificate authorization from the respective state commissions.[32] Specifically, Exelon states that the Project requires the acquisition of approximately 50 acres of land in Pennsylvania for the new West Cooper substation and Peach Bottom Expansion, as well as 1.25 miles of expanded rights-of-way in York County, Pennsylvania. In addition, Exelon states that new transmission facilities within existing rights-of-way in Maryland will require the need for Maryland Public Service Commission approval. Accordingly, Exelon argues, the Abandoned Plant Incentive requested in this application is narrowly tailored to the risks of project failure with no other incentives or protections being sought, thus demonstrating that this limited request is fully justified and should be granted.[33]

20. Exelon acknowledges that, consistent with the Commission's precedent, in the event that the Commission approves the Abandoned Plant Incentive and Exelon incurs abandoned plant costs, BGE, PECO, and/or Pepco would submit a separate section 205 filing demonstrating that any costs it seeks to recover were prudently incurred and that the abandonment was due to events outside of Exelon's reasonable control.[34]

b. Determination

21. We grant Exelon's request for the Abandoned Plant Incentive for the Project, effective December 20, 2023, as requested.

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[31] *Id.* at 11.

[32] *Id.*

[33] *Id.* at 12.

[34] *Id.* at 14 n.43 (citing Order No. 679, 116 FERC ¶ 61,057 at P 166).

22. In Order No. 679, the Commission found that the Abandoned Plant Incentive effectively encourages transmission development by reducing the risk of non-recovery of costs in the event that a project is abandoned for reasons outside the applicant's control.[35] We find that the Project faces risks beyond Exelon's control that could lead to the Project's abandonment, and that approval of the Abandoned Plant Incentive will address those risks. Thus, we find that Exelon has demonstrated a nexus between its requested incentive and its planned investment, and that Exelon has tailored its incentive request to its identification of risks and challenges associated with the Project.

23. Consistent with Commission policy, the Abandoned Plant Incentive for the Project will be available to Exelon for 100% of prudently incurred costs expended on and after the effective date granted in this order if the Project is abandoned for reasons beyond Exelon's control. We will not determine the prudence of any costs incurred prior to the abandonment, if any, until Exelon seeks such recovery in a future FPA section 205 filing that a public utility is required to make if it seeks abandoned plant recovery.[36]

24. As a result of the Commission approving the rate incentive, Exelon must submit FERC-730 reports annually.[37] Finally, we accept Exelon's tariff record submitted with its filing, to become effective December 20, 2023, as requested.

<u>The Commission orders</u>:

(A) Exelon's request for the Abandoned Plant Incentive is hereby granted for the Project, effective December 20, 2023, as requested, as discussed in this order.

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[35] Order No. 679, 116 FERC ¶ 61,057 at PP 163-166; *see also, e.g., Midcontinent Indep. Sys. Operator, Inc.*, 153 FERC ¶ 61,296, at P 28 (2015); *TransCanyon DCR, LLC*, 152 FERC ¶ 61,017, at P 41 (2015).

[36] Order No. 679, 116 FERC ¶ 61,057 at PP 165-166. In the event that Exelon seeks abandoned plant recovery for the time period prior to the effective date of this order, Exelon would be eligible to seek recovery of 50% of its prudently incurred costs, consistent with prior precedent. *See, e.g., San Diego Gas & Elec. Co.*, 154 FERC ¶ 61,158, *order on reh'g*, 157 FERC ¶ 61,056 (2016), *aff'd sub nom. San Diego Gas and Elec. Co. v. FERC*, 913 F.3d 127 (D.C. Cir. 2019).

[37] FERC-730 annual reports, which contain actual, projected, and incremental transmission investment information, must be filed by public utilities that have been granted incentive rate treatment for specific transmission projects. 18 C.F.R. § 35.35(h). These reports contain actual, projected, and incremental transmission investment information.

(B) Exelon’s eTariff records are accepted, to become effective December 20, 2023, as discussed in this order.

By the Commission. Commissioner Danly is not participating.
Commissioner Christie is concurring with a separate statement attached.

(S E A L)

Debbie-Anne A. Reese,
Deputy Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. Docket No. ER24-163-000

(Issued December 19, 2023)

CHRISTIE, Commissioner, *concurring*:

1. Today's order is consistent with the Commission's existing policies regarding the Abandoned Plant Incentive, as articulated in Order No. 679;[1] thus, I will concur rather than dissent. This order illustrates, however, why I believe the Commission needs to revisit the array of incentives offered to transmission developers, including the Abandoned Plant Incentive addressed in this order as well as the Construction Work in Progress (CWIP) Incentive and the RTO participation adder.[2]

2. A core principle of utility law and regulation for decades is that consumers can only be forced to pay costs for assets that are "used and useful" to them. In Order No. 679, the Commission determined that it may be necessary to depart from this long-standing ratemaking principle to "address the substantial challenges and risks in constructing new transmission."[3] In prior statements, I questioned, among other concerns, whether the Commission's determination of whether "substantial challenges and risks" exist when granting the Abandoned Plant Incentive and other incentives has become nothing more than a check-the-box exercise.[4]

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[1] *Promoting Transmission Inv. through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057, *order on reh'g*, Order No. 679-A, 117 FERC ¶ 61,345 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

[2] I recognize that the CWIP Incentive and the RTO participation adder are not at issue in this proceeding.

[3] Order No. 679, 116 FERC ¶ 61,057 at PP 26, 117.

[4] *See, e.g.*, *The Potomac Edison Co.*, 185 FERC ¶ 61,083 (2023) (Christie, Comm'r, concurring at P 2), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-concerning-potomac-edisons-abandoned-plant; *Montana-Dakota Utils. Co.*, 185 FERC ¶ 61,015 (2023) (Christie, Comm'r, concurring at P 2), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-montana-dakota-utilities-co-regarding; *Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,136 (2023) (Christie, Comm'r, concurring at P 2), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-midcontinent-independent-system-operator-inc-0; *GridLiance W. LLC*, 184 FERC ¶ 61,129 (2023) (Christie, Comm'r,

3. As I noted previously:

> The Commission's incentive policies—particularly the CWIP Incentive, which allows recovery of costs *before* a project has been put into service—run the risk of making consumers "the bank" for the transmission developer; but, unlike a real bank, which gets to charge interest for the money it loans, under our existing incentives policies the consumer not only effectively "loans" the money through the formula rates mechanism, but

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concurring at P 2), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-gridliance-west-regarding-transmission; *Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,034 (2023) (Christie, Comm'r, dissenting at P 2), https://www.ferc.gov/news-events/news/commissioner-christies-dissent-award-transmission-incentives-nipsco-er23-1904; *Otter Tail Power Co.*, 183 FERC ¶ 61,121 (2023) (Christie, Comm'r, concurring at P 2), https://www.ferc.gov/news-events/news/e-18-commissioner-christies-concurrence-otter-tail-power-company-regarding; *LS Power Grid Cal., LLC*, 182 FERC ¶ 61,201 (2023) (Christie, Comm'r, concurring at P 2), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-ls-power-grid-regarding-transmission-incentives; *Nev. Power Co.*, 182 FERC ¶ 61,186 (2023) (Christie, Comm'r, concurring at P 2), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-nv-energy-regarding-transmission-incentives; *The Dayton Power and Light Co.*, 182 FERC ¶ 61,147 (2023) (Christie, Comm'r, concurring at P 2), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-dayton-power-and-light-company-regarding; *Midcontinent Indep. Sys. Operator, Inc.*, 182 FERC ¶ 61,039 (2023) (Christie, Comm'r, concurring at P 2), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-midcontinent-independent-system-operator-inc; *NextEra Energy Transmission Sw., LLC*, 180 FERC ¶ 61,032 (2022) (Christie, Comm'r, concurring at P 2) (July 2022 Concurrence), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-nextera-energy-transmission-southwest-llc; *NextEra Energy Transmission Sw., LLC*, 178 FERC ¶ 61,082 (2022) (Christie, Comm'r, concurring at P 2) (February 2022 Concurrence), https://www.ferc.gov/news-events/news/commissioner-mark-c-christie-concurrence-nextera-energy-transmission-southwest-llc. *See also DCR Transmission, L.L.C.*, 184 FERC ¶ 61,199 (2023) (Christie, Comm'r, concurring at P 6), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-dcr-transmission-regarding-transmission-cost.

> also pays the utility a profit, known as Return on Equity, or "ROE," for the privilege of serving as the utility's *de facto* lender.[5]

Further, just as the CWIP Incentive effectively makes consumers the bank for transmission developers, the Abandoned Plant Incentive effectively makes them the insurer of last resort as well. This incentive allows transmission developers to recover from consumers the costs of investments in projects that fail to materialize and thus do not benefit consumers. Just as consumers receive no interest for the money they effectively loan transmission developers through CWIP, they receive no premiums for the insurance they provide through the Abandoned Plant Incentive if the project is never built. And if the CWIP Incentive is a *de facto* loan and the Abandoned Plant Incentive is *de facto* insurance — both provided by consumers — then the RTO participation adder, which increases the transmission owner's ROE above the market cost of equity capital, is an involuntary gift from consumers.[6] There is something really wrong with this picture.

4. As this Commission considers other potential reforms related to regional transmission planning and development, it is imperative that incentives like the CWIP Incentive, Abandoned Plant Incentive, and RTO participation adder are all revisited to ensure that all the costs and risks associated with transmission construction are not unfairly inflicted on consumers while transmission developers and owners stand to gain all the financial reward. Moreover, if the Commission determines it is appropriate to channel risks to consumers, those risks must be carefully weighed and considered and not simply be mitigated at the expense of consumers in an exercise of "check-the-box."

5. Early in 2021, a majority of this Commission voted to approve a supplemental notice of proposed rulemaking which proposed, among other things, to limit the RTO participation adder to the three years following a transmitting utility's initial membership

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[5] February 2022 Concurrence at P 3 (emphasis in original); July 2022 Concurrence at P 3 (citation omitted); *see also Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation & Generator Interconnection*, 179 FERC ¶ 61,028 (2022) (Transmission Planning and Cost Allocation NOPR) (Christie, Comm'r, concurring at P 15) ("CWIP is, of course, passed through as a cost to consumers, making consumers effectively an involuntary lender to the developer . . . . Consumers should be protected from paying CWIP costs during this potentially long period before a project actually enters service, if it ever does."), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-e-1-regional-transmission-planning-and-cost.

[6] *See, e.g., Rockland Elec. Co.*, 178 FERC ¶ 61,232 (2022) (Christie, Comm'r, concurring at P 4), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-rockland-electric-er22-910.

in an RTO.[7] I joined in that vote and continue to support such a time limit. That supplemental notice of proposed rulemaking remains pending. Likewise, the Commission proposed to eliminate the CWIP Incentive in its April 2022 Transmission Planning and Cost Allocation NOPR,[8] which I described as "a major step forward in consumer protection and is a big reason I am voting for [the NOPR]."[9] It is clear to me that the Commission's procedures and criteria for awarding the Abandoned Plant Incentive should also be reconsidered. In short, revisiting all these incentives is imperative at a time of rapidly rising customer power bills.

6. I note that in describing the various risks associated with its Brandon Shores RTEP projects for which Exelon seeks an Abandoned Plant Incentive, Exelon appears to mention potential risks from state public policy projects. For example, Exelon states:

> There are redundancies between elements of the Brandon Shores Project [at issue in this docket] and the [New Jersey Off Shore Wind State Agreement Approach (SAA)] North Delta Project. This issue, and the related redundancies, have not yet been resolved by PJM, which in turn places the related elements of both projects into a state of uncertainty and developmental risk.[10]

Whether or not the development of Exelon's Brandon Shores Project will be impacted by another state's public policy projects is currently uncertain, but as I said in a previous statement related to the New Jersey SAA public policy wind project, all costs associated with the state public policy projects must be paid for by New Jersey unless another state voluntarily chooses to share those costs and the SAA itself makes that clear.[11]

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[7] *Elec. Transmission Incentives Policy Under Section 219 of the Fed. Power Act*, Supplemental Notice of Proposed Rulemaking, 175 FERC ¶ 61,035, at P 9 (2021).

[8] Transmission Planning and Cost Allocation NOPR, 179 FERC ¶ 61,028 at P 333 & n.530.

[9] *Id.* (Christie, Comm'r, concurring at P 15).

[10] Transmittal at 10 (footnote omitted).

[11] *See, e.g.*, *PJM Interconnection, L.L.C.*, 179 FERC ¶ 61,024 (2022) (New Jersey SAA Agreement Order) (Christie, Comm'r, concurring at P 3 (quoting New Jersey SAA Agreement Order at P 43 (emphases in original and added) (citations omitted)) (https://www.ferc.gov/news-events/news/commissioner-mark-c-christies-concurrence-pjm-nj-bpu-state-agreement-saa-approach)) ("'While we therefore can make no determination as to any future cost allocations arrangements here, and, as a result, we similarly do not speculate as to the identity of any "future users," this Commission need

7. With respect to today's order, I also note that just under six weeks ago I issued a statement concurring in the Commission's order accepting cost responsibility assignments for the PJM transmission projects related to the deactivation of Brandon Shores.[12] It is also Brandon Shore's related transmission projects concerning which

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not speculate as to who *cannot be among the future users* in any future cost sharing arrangement: the *future users may not include a state other than New Jersey or that state's customers unless that state, consistent with the State Agreement Approach, voluntarily agrees to make its customers responsible for any costs. Any attempt otherwise is contrary to the basic tenets of the State Agreement Approach and is not accepted by the Commission in this order*. We note that PJM and NJ BPU agree with this premise and explain that in any such future cost allocation filing, consistent with the requirements of the Operating Agreement, those "future users" contemplated by the cost sharing provision would not include customers of a state that has not voluntarily agreed to be responsible for such costs. We base our acceptance of the SAA Agreement on our understanding in this regard.'"); New Jersey SAA Agreement Order at P 40 (quoting State Agreement Approach, OA Schedule 6 Sec 1.5, § 1.5.9(a)) ("The State Agreement Approach also requires that '[a]ll costs related to a state public policy project or Supplemental Project included in the Regional Transmission Expansion Plan to address state Public Policy Requirements pursuant to this Section shall be recovered from customers in a state(s) in the PJM Region that agrees to be responsible for the projects.'"). I have drawn similar conclusions concerning the costs of state public policy projects in a number of dockets not involving PJM's SAA. *See, e.g.*, *N.Y. Indep. Sys. Operator, Inc*., 184 FERC ¶ 61,059 (2023) (Christie, Comm'r, concurring at P 3 (quoting Consol. Edison Co. of N.Y., 180 FERC ¶ 61,106 (2022) (Christie, Comm'r, concurring at P 4 (footnote and citations omitted)) (https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-new-york-transmission-cost-allocation-case-er23)) ("'[T]here is nothing in the record in this matter to indicate that any of the costs of the transmission projects that will be built to implement New York's public policies under the terms described in this proposal will be forced on consumers in other states. As I have also said before, if the record showed costs for New York's policies were being imposed on consumers in states that had not consented to such cost allocation, that would be a much different story and would quite likely result in unjust and unreasonable rates. And claiming that such consumers were somehow "beneficiaries" of New York's public policies, when out-of-state consumers had no say in electing the New York politicians adopting such policies, would not cure the fundamental unjustness and unreasonableness of such cost allocation.'"); *NSTAR Elec. Co.*, 179 FERC ¶ 61,200 (2022) (Christie, Comm'r, concurring at P 10 (https://www.ferc.gov/media/e-13-er22-1247-000)) ("To reiterate, imposing the costs of a project driven by one state's public policies onto another state that has not consented to such cost allocation would, in my view, presumably result in unjust and unreasonable rates.").

[12] *PJM Interconnection, L.L.C.*, 185 FERC ¶ 61,107 (2023) (Christie Brandon

Exelon seeks the Abandoned Plant Incentive in this docket. I recognized in my statement that the projects were "very costly," and this order further emphasizes that: Exelon describes in this docket an "approximately *$785 million Project* [] needed for reliability because of the announced retirement of Talen Energy's Unit 1 and Unit 2 at the 1,240 MW coal-fired Brandon Shores Generating Station."[13]

8. In my Brandon Shores RTEP Concurrence, I also observed the following regarding these costs and their consideration by the PJM states:

> [I]f the resulting transmission projects under protest in this RTEP filing are caused more by Maryland's policy choices than by organic load growth and economic resource retirements, then a salient question that may be asked is whether these transmission projects are more accurately categorized as public policy projects, essentially the same as the transmission upgrades caused by New Jersey's offshore wind projects? And if they are more accurately categorized as public policy projects, should such projects be regionally cost-allocated, potentially to consumers in Pennsylvania, West Virginia, Ohio, et al.? For example, the State of Illinois has a law similar to Maryland's that PJM has already estimated will cause $2 billion in transmission upgrades, costs that will be allocated to consumers in other states under PJM's existing cost-allocation formula. These are questions that the states within [the Organization of PJM States (OPSI)] may wish to start considering, as some already have. As the National Association of Regulatory Utility Commissioners (NARUC) noted in comments filed at FERC: ". . . the PJM states are not voting members of PJM, but the majority have reached an equally valid agreement that the burden for costs driven by public policy requirements of one state should not be placed on customers of load serving entities in non-participating states."[14]

9. I also reminded the states in PJM that PJM is not a regional IRP planner:

> It is ultimately the job of each state to ensure resource adequacy to serve its consumers, *even in a multi-state RTO*. So while I am deeply sympathetic to the concerns expressed by the [Maryland Public Service Commission],

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Shores RTEP Concurrence), https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-pjm-transmission-projects-cost-allocation-er23.

[13] Order at P 3 (emphasis added).

[14] Christie Brandon Shores RTEP Concurrence at PP 7-8 (footnotes omitted) (quoting NARUC, Motion to Intervene and Comments, Docket No. RM21-17-000, at 24 (filed Oct. 12, 2021)).

> OPSI and the [Maryland Office of People's Counsel] as to the impact on consumers, there is really no practical choice for us but to approve this filing. We simply cannot risk the potentially catastrophic consequences laid out by PJM in its filing. But the states in OPSI, as well as all states in multi-state RTOs, may want to consider the broader questions this filing raises, as I have described above.[15]

10. My suggestions in my Brandon Shores RTEP Concurrence are as important today as they were six weeks ago, perhaps even more so as we consider the impact on consumers of an Abandoned Plant Incentive on $785 million dollars' worth of projects.

For these reasons, I respectfully concur.

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Mark C. Christie
Commissioner

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[15] Christie Brandon Shores RTEP Concurrence at PP 10-11 (emphasis in original) (footnotes omitted).